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Attachment A

Joint California Public Utilities Commission and California Energy Commission Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol

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Executive Summary

California Assembly Bill 32 requires that the Air Resources Board (ARB), in coordination with the California Public Utilities Commission and the California Energy Commission, develop and adopt reporting protocols for monitoring greenhouse gas (GHG) emissions associated with serving California's retail electric load. For the purposes of this proposed reporting protocol, retail providers include investor-owned utilities, publicly-owned utilities, energy service providers, community choice aggregators, and the Western Area Power Administration. Reports using these reporting protocols will complement the source-based reporting overseen by ARB.

The following whitepaper is a draft proposal for the tracking and reporting of GHG emissions associated with all retail sales of electricity within California. It will serve as the basis for public written comments and reply comments. Following receipt of these comments, a proposed decision will be published. Upon the adopting of a decision, the two Commissions will send the recommendations to ARB in September. The ARB must adopt final reporting regulations by the end of 2007.

In order to assign responsibility for GHG emissions to retail providers and to improve the statewide estimate of emissions attributed to the electric sector, a fuel source must be assigned to all generation produced to serve load. While this is straight-forward for owned units and for other specified sources, emission factors must be estimated for unspecified sources, whether generated in-state or imported from out-of-state. The conceptual difficulties stem mainly from three factors: 1) identifying the sources of imports and exports, 2) tracking in-state trades, and 3) the difference between contracted energy and actual dispatch. For establishing historic and current emission responsibilities, available data must be used. However, future tracking can be refined to collect additional information.

The proposal recommends that retail providers identify power received from owned assets and other specified sources, so that emissions from individual plants can be accurately allocated. Emissions reported from these facilities will be matched by the source-based data submitted to ARB. For purchases from asset-owning sellers who provide power on an aggregate basis, a provisional certification process is proposed so that the seller may have an emission factor certified on the basis of its portfolio.

Gross wholesale purchases and sales will be reported separately. Default emission factors are proposed for system purchases from out-of-state, from the California Independent System Operator's (CAISO's) day-ahead and real-time markets, and from marketers and brokers. The default factors are based on operational characteristics of the various markets, known system attributes, modeling, and transmission limits, and are summarized in Table ES-1.

Table ES-1. Summary of Recommended Emission Factors

TYPE OF PURCHASE	RESOURCE TYPE	CO_2 EMISSION FACTOR (LBS/MWH)
In-state specified source	All fuels	Use emission factor source has provided to ARB for certification
Out-of-State specified source, includes ownership shares and contracts	Mostly coal, some renewables, gas, and nuclear	Calculate emission factor based on ARB methods. Coal factor range is 2,017 – 2,263
CAISO real time energy pool	Balancing energy *Mostly gas and hydro*	Use default factor of 900
CAISO Integrated Forward Market (pool)	All fuels, both in and out of state	Use default factor of 1,000
Other in-state unspecified sources	Unknown	Use default factor of 1,000
Out-of-state specified sellers (system purchase from asset-owning entity	Depends on seller	Request seller to obtain system average certification from ARB, net of resources claimed to serve native load
Northwest unspecified marginal generation	69% carbon-free, mostly hydro	Use default rate of 419
Southwest unspecified marginal generation	90% gas, 10% coal	Use default rate of 1,075

Wholesale sales will be assigned an emissions factor based on an adjusted all-in method. This method assumes that the retail provider selling wholesale power is providing the power from its total system mix, including gross purchases. However, the mix would be adjusted to subtract claimed resources. A path will be provided for retail providers who can document that a particular plant was the generation source for particular wholesale sales.

This paper also addresses the mechanics of reporting, such as what will be reported, frequency of reporting, requirements for verification, certification of third-party auditors, and methods to address potential contract shuffling and leakage.

The proposal includes a recommendation to expand on staff's efforts to date to work with other states in the region on a consistent regional tracking system. In particular, California would work with Washington and Oregon to develop a pilot project to ensure that the tracking systems in all three states exclude generation otherwise claimed to serve native load.

The proposal is based on information presented at the April 12 and 13 Commissions' workshops, subsequent ARB workshops, documentation of suggestions made by parties, and existing reporting protocols of the Energy Commission and the California Climate Action Registry. The paper recommends that reporting protocols implemented in 2008 be reviewed no later than 2011 so that they can be refined for the first compliance year in 2012.

1. Reporting Greenhouse Gas Emissions Associated with Electricity Consumption

Establishing a consistent emissions accounting convention for the sources of generation used to serve California load is necessary to implement Assembly Bill 32, the California Global Warming Solutions Act of 2006 (AB 32). Statewide greenhouse gas (GHG) emissions are defined in AB 32's Section 38505 (m) to mean: "the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation from electricity delivered to and consumed in California, accounting for the transmission and distribution line losses, whether the electricity is generated in state or imported."

AB 32 Part 2, Mandatory Greenhouse Gas Emissions Reporting, Section 38530 requires the California Air Resources Board (ARB) to adopt reporting and verification regulations for GHG emission sources that "account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from generation within the state or imported from outside of the state." It further specifies that the requirement to report applies "to all retail sellers of electricity." Since the cap described in AB 32 applies to emissions associated with electricity consumed in California, from both in-state and out of state sources, the emissions associated with imported power must be accounted for in the electricity sector reporting protocol.

While there may be practical barriers to the accurate tracking and reporting of emissions associated with out-of-state generation that do not exist for generation for in-state sources, this proposal recommends that, for the sake of consistency, the reporting protocols for all sources, both in-state and out-of-state, have the same ultimate effect.

In response to the mandate of AB 32, the California Energy Commission and the California Public Utilities Commission will each adopt a decision to recommend an Electricity Retail Provider Reporting Protocol (Protocol) to ARB. This joint staff proposal outlines staff's thoughts on a proposed Protocol for consideration by the Commissions.

1.1 Implementing a Load-based Tracking System in the Electricity Sector

A load-based tracking approach assigns responsibility to each electric retail provider for the GHG emissions associated with the electricity generated to serve its load.[1] In order to quantify retail providers' GHG emissions, and to improve the statewide estimate of emissions attributed to the electric sector, fuel sources must be assigned to all generation produced to serve California load. While this is straight-forward for owned units and for other specified sources (see Section 2.1), it must be estimated for unspecified sources, whether generated in-state or imported from out-of-state. The conceptual difficulties stem mainly from three factors: 1) identifying the sources of imports and exports, 2) tracking in-state trades, and 3) the difference between contracted energy and actual dispatch.

[1] This paper addresses reporting rules for a load-based approach. The issue of whether a load-based cap is the appropriate approach will be addressed elsewhere in this proceeding.

1.2 California's Dependence on Imported Electricity

California's electricity system was built to take advantage of Western regional resource diversity and non-coincident seasonal demands. Large interstate transmission lines interconnect the state with both the Northwest and the Southwest. Historically, net imports over these lines have accounted for about 20% of total electricity used in the state, with a range of 15% to 23% depending on hydroelectric availability, power needs and relative prices. The Southwest's share of total imports has grown steadily from about half of all imports in 1990 to three-fourths of imports today (California Dept. of Finance, 2005).

The specific source of just over half of these imports is already known. Using 2005 data, 56% of net imports could be traced to a known source, while 44% came from unspecified sources (Alvarado and Griffin, 2007). Although a much larger proportion of Northwest imports (88%) is currently unspecified compared to Southwest imports (29%), unspecified imports from the Southwest (18,083 GWh) were slightly larger than those from the Northwest (17,882 GWh) because California imports more power from the Southwest.

1.3 In-state Unspecified Purchases

Many parties sell power to retail providers from plants within California through arrangements in which the specific plants providing the power are not known. Independent Power Producers (IPPs) typically sell power to retail providers from a fleet of the plants they own. Marketers, which do not own assets but package generation and resell it in other formats to meet the specific needs of buyers, account for a substantial share of the California market. Contracts such as "liquidated damages contracts" have provided economic benefits to California consumers through the bundling and unbundling of services provided by marketers. While liquidated damages contracts are being phased out for resource adequacy purposes, they still play a role in the energy markets. Buyers do not know the source of the generation in these deals.

Both the existing CAISO real time markets and the forthcoming integrated forward market (IFM) are power pools, where the CAISO conducts least-cost dispatch by matching bids to loads on an aggregated basis. The real time market serves a vital function by efficiently balancing small amounts of energy. This market currently serves about 5% of the total CAISO demand, and it is estimated that the IFM may handle 10 - 20% of total energy once it is operational (Market Advisory Committee, 2007, p. 43). Because these transactions draw from pools, the link between a specific seller and a specific buyer does not exist.

In this trading market, multiple parties and facilities may be involved in a chain of purchases and sales. A seller may buy a single block of energy and then disaggregate it and sell smaller portions to multiple new purchasers. A buyer may be able to arbitrage between what is available at one time and the price of it at a future time. Sellers or buyers may be able to enhance the value of a product through transmission access or firming capacity.

1.4 Lack of a Comprehensive "Source to Sink" Reporting System

Comprehensive generation information systems are currently operational in NEPOOL and PJM transmission areas in the northeastern United States. These systems record generation and emissions from all plants in these multi-state regions. Additionally, they provide information on where most of the electricity generated in these regions sinks, meaning which entity ultimately takes title of the MWh generated and associated emissions.

A similar system could be developed for the Western Electricity Coordinating Council (WECC) region, but only if all (or most) states and provinces in WECC also required the power plants located in their states to participate in the tracking system. In the absence of caps in other WECC states and provinces, even a comprehensive tracking system could not prevent contract shuffling, a non-compliance strategy described in more detail below. With widespread caps and tracking system participation, market participants could bid against each other for cleaner resources, rendering default assumptions unnecessary.

Tracking electricity generation from source to sink is complicated by both actual market operations and data availability. While the system is dispatched on a least-cost, transmission-constrained basis, buyers and sellers engage in multi-year, seasonal, daily and hourly sales and exchanges. Energy may be sold multiple times and financial settlements may not match actual dispatch. Tracking of generation currently does not account well for gross exports across state lines or trading.

Currently, data are available on specified purchases and total amounts of imported energy. The investor-owned utilities (IOUs) and many of the publicly-owned utilities (POUs) have been reporting their specified purchases to state agencies for a number of years under other programs. The Energy Commission has a historic base for specified sources which is easy to update. For unspecified sources, control totals are available and some data can be mined on the sources of this power.

2. Key Issues, Definitions, and Criteria for the Protocol

2.1 Definitions

2.1.1 Retail Provider

For purposes of this protocol, the term "retail provider" refers to all entities providing electricity to end users. Thus, "retail provider" includes all investor owned-utilities (IOUs), publicly-owned utilities (POUs), Electric Service Providers (ESPs), Community Choice Aggregators (CCAs), and the Western Area Power Administration (WAPA)[2] serving customers in California and is therefore synonymous with the entities required to report their emissions under this protocol.

2.1.2 Power Plant

Consistent with the definition of a power plant in the Public Utilities Commission decision D.07-01-039 (the Emission Performance Standard) and in the Emissions Performance Standard regulations adopted by the Energy Commission on May 23, 2007, a power plant is a facility for the generation of electricity comprised of one or more generating units if: 1) the

[2] We recognize that most of WAPA's sales in California are not to end users. The proposed reporting requirements would only apply to WAPA's sales to the extent that they are to end users.

units are at the same location, 2) each unit utilizes the same resource (fuel), and 3) and one or more units are operationally dependent on another.

2.1.3 Specified Sources

Specified sources are power plant-level sources of electricity generation that a retail provider can confidently track to its own load due to full or partial ownership or a firm contractual relationship, such as a long-term power purchase agreement (PPA).

2.1.4 Unspecified Sources

Unspecified sources of electricity are all purchases of electricity that cannot be matched to a particular power plant. Unspecified sources include purchases from entities that own fleets of power plants such as independent power producers, utilities, and federal power agencies as well as purchases from marketers, brokers, and markets.

2.1.5 Point of Delivery

A point of delivery is a point on an electric system where a power supplier delivers electricity to the receiver of that energy. This point could include an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

2.1.6 Point of Receipt

A point of receipt is a point on an electric system where an entity receives electricity from a supplier. This point could include an interconnection with another system or generator busbar. In a wholesale electricity transaction, the point of receipt is the location where the electricity enters the transmission and the point of delivery is the location where the electricity sinks.

2.1.7 Net Purchases

Net purchases are the difference between a retail provider's wholesale sales and wholesale purchases.

2.1.8 Asset Owning Entity

An asset owning entity refers to any entity owning electricity generation facilities that deliver electricity to a transmission or distribution line. This definition may include independent power producers, qualifying facilities (QFs), IOUs, POUs, state agencies, federal agencies, and CCAs.

2.1.9 Control Area[3]

A control area (or balancing authority) is a region defined by the North America Electric Reliability Corporation (NERC) having one entity that operates the transmission grid and provides open, non-discriminatory access to the transmission grid.

2.1.10 Leakage

Leakage refers to the phenomenon in which efforts to mitigate environmental damages in one location induce unintended increases in environmental damage elsewhere. In AB 32, leakage is defined as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." This could occur if GHG regulations result in the relocation of electricity generation (or production of other goods) from California to other states or countries that do not have GHG caps. Emissions in California would decline as a consequence, but they would increase at the location where the increased generation occurs.

2.1.11 Contract Shuffling

Contract shuffling describes a system of contractual arrangements that could be used to facilitate leakage when electricity is imported from an uncapped system into a capped system that includes emissions associated with imports. For example, contract shuffling would occur if a California retail provider enters into a contract with a supplier for power from a specified low-carbon facility, but the payments to the supplier are actually used to increase generation at a different plant or a mix of plants. Another example would be when a California retail provider stopped buying power from a high-carbon resource in favor of a lower-carbon resource, but the high-carbon resource was simply resold to another buyer in an uncapped region. On paper, the California retail providers would have lower emissions burdens than was truly induced through purchases.

2.1.12 Emission Factors

An emission factor is a ratio that is used to calculate emissions of a given pollutant per unit of energy consumed. Emission factors are used to convert combusted fuels to quantities of pollutants, e.g., lbs. CO_2e/MMBtu. Emission factors can also be calculated for the end use of electricity based on what is known about the types and quantities of fuels combusted to produce the power delivered to end users.

2.2 Issues

2.2.1 Covered Entities

The Retail Provider GHG Reporting Protocol applies to every electrical corporation, electric service provider, or community choice aggregator serving end-use customers in California, collectively referred to as load-serving entities (LSEs) in these rules. It also applies to POUs as defined in Public Utilities Code 9604. The five categories of POUs include municipalities

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[3] Control area is being replaced with the term "balancing authority."

(cities), municipal utility districts, public utility districts, irrigation districts and joint powers authorities.

A small share of power in California is sold directly from WAPA to certain federal and state facilities. WAPA should report the emissions associated with all of its sales to end-users in California. This will allow us to maintain a complete and accurate inventory of California GHG emissions.

2.2.2 Evolution of the Reporting System as Methodologies and Tracking Systems are Developed

It is very likely that the reporting protocol adopted for 2008 reporting will change as lessons are learned from the initial implementation. Electricity markets and the physical systems used to produce and deliver electricity are exceedingly complex. Working with ARB in its role of managing all mandatory reporting, the Public Utilities Commission and the Energy Commission will continue to refine the methodologies used to estimate GHG emissions associated with unspecified sources. Moreover, the State is currently working with other parties to explore generation information systems and tracking mechanisms that could largely automate the attribution of emissions to particular parties.

In addition to deepening analytical capability with load-based methodologies, future policy developments may necessitate changes to the reporting protocol. One particularly important development is the Memorandum of Understanding (MOU) to establish a regional GHG cap for the Western states that are signatories. To date, the MOU has been signed by the governors of six Western states (California, Washington, Oregon, Arizona, New Mexico, and Utah) and the premier of British Columbia. So far, few details have emerged concerning how the MOU will be implemented. Several federal climate change bills have also been proposed, and the enactment of a federal GHG program could significantly affect the policy environment in which reporting occurs.

In the future, a WECC-wide tracking system may materialize with emission-labeled contracts that also accounts for the claimed resources in other states. In the meantime, tracking rules should be designed to minimize or penalize contract shuffling and leakage, account for out-of-state resources that are claimed for other purposes than sale to California, allow for greater seller-specificity, and be administratively feasible. Any rule adopted this year is likely to be reviewed and updated as the actual implementation of the GHG emissions cap in 2012 approaches.

2.3 Criteria

Choices made among possible reporting protocol methods will have significant implications for the final emission burden ascribed to a given retail provider. The criteria to be considered in the course of determining the final recommendation are described below.

2.3.1 Accuracy

To the extent possible, the reporting protocol should be designed to produce an accurate estimate of the GHG emissions that result from the consumption of electricity in California, at both the retail provider level and the statewide total. While it is not possible to ascertain precisely which power plants are induced to operate to provide power to California end-users, the protocol should not yield emission totals that deviate substantially from the results of in-depth analysis.

2.3.2 Consistency

Under the voluntary California Climate Action Registry (Registry) protocol, reporting retail providers were allowed to select from multiple emission factors to characterize the emissions associated with their purchases. In order to maintain consistency among reporting parties, similar purchases should be treated equally regardless of the retail provider making the purchase. To this end, all reporting entities should use the same emission factors for the same sources of purchased electricity.

All of the Protocol options considered by the Commissions require consistency in the calculation of emissions among the reporting retail providers. Therefore, this criterion is not examined further in the assessment of individual elements of the Protocol in subsequent sections.

2.3.3 Simplicity

The final reporting protocol should not impose an overly burdensome procedure on either reporting entities or the state agencies overseeing the program. While the reporting burden is a consideration, a balance must be struck between the desire to avoid an unnecessarily complex protocol and the need to ensure a level of rigor that yields a defensible level of accuracy.

2.3.4 Transparency

Related to the simplicity criterion is the necessity of maintaining transparency in the assumptions about the electricity system and California's influence on emissions occurring in other states. To the extent possible, any derived emission factors used for reporting should use publicly available data and any assumptions underlying modeling or other analysis should be explicit.

2.3.5 Minimization of Unintended Consequences

The reporting method should not distort the electricity markets by causing retail providers to make non-optimal resource choices. Clearly, the reporting system should accurately report retail providers' activities and choices, and should allow them to document that they are complying with the targets and policy directions of reducing GHG emissions. At the same time, the reporting protocol should not incentivize buyers or sellers to misuse the IFM or the real-time market. The IFM has been designed to optimize the efficient use of the transmission system while encouraging least-cost dispatch. However, several parties have expressed concern about the lack of control that retail providers will have to determine what resources are dispatched into the IFM. Some parties worry that in order to control their emissions burden, retail providers will be forced to self-schedule more power, which undermines the benefits of the IFM and Market Redesign. The State will work closely with retail providers and the CAISO to design a system that does not disincentivize use of the IFM.

2.3.6 Setting Appropriate Policy Signals

While the reporting method should be designed to report accurate emissions attributable to the retail providers, complete accuracy is not possible. Where estimation is needed, care should be taken that the Protocol provides incentives that tend to reduce overall GHG emissions.

2.3.7 Expandability

This reporting system is being designed to implement California's GHG reduction requirements, but six states and one Canadian province have signed an MOU to develop a regional cap and a regional market-based multi-sector mechanism to achieve that goal. One aim of this system should be that it can be readily expanded to other states without changing the reported emission profile of load-serving entities. For example, a system might attribute emissions from owned sources in California to the owning utility, but treat out-of-state resources as part of an overall system mix used to estimate the emissions from electricity imported into California. If that system were then expanded to cover a wider region, the State of California should seek agreement with states in the larger region about which sources owned by out-of-state utilities provide power for export and which sources serve native load.

3. Review of Existing Methods for Estimating Resources or Emissions Associated with Electricity Serving California Load

3.1 Regional Averages for Imports

The Energy Commission has attempted to ascertain the resources used to serve California load using various methods dating back to 1988. Appendices A and C of the most recent California GHG inventory (Bemis, 2006) provide an overview of three different methods that have been used to quantify the emissions associated with California's electricity imports. Two of the methods referred to have been used in published California GHG inventories. These two methods use separate average emission rates for the Northwest and Southwest regions and applied these two rates to all imports (other than two coal plants located out of state but operated by California utilities) from each region.

Much of the work conducted by the Energy Commission has focused on estimating the fuel types of the resources serving California rather than the GHG emissions per se. These studies have largely been conducted to fulfill the requirements of Senate Bill 1305 (Sher, Statutes of 1997), a bill intended to provide consumers with verified information on green power products offered by utilities. This law directs the Energy Commission to determine the resource mix of power supplying California and to verify claims by any retail provider that its power, or a specific electricity product, differs from the California mix. Each year since 1999, the Energy Commission has produced a net system power report that describes the resource mix of power delivered to California customers. The 2005 net system power report estimates that the gross system power as 20 percent coal and 38 percent natural gas, with the remainder from zero emission sources (Marks et al., 2006).[4] Similar to the California GHG inventories,

[4] Gross system power denotes the sum of all in-state generation and electricity imports by fuel type. Net system power is the residual power that remains after all self-generation and facility-specific purchases have been subtracted.

the net system power reports have used the average mix of resources from the Southwest and Northwest for the imports from each of those regions.

A study conducted by Lawrence Berkeley National Laboratory (LBNL) for the Public Interest Energy Research Program examined 1990 and 1999 emissions from in-state facilities and imports (Marnay et al., 2002). This study utilized three different methods (average factors from public data, a load-duration curve model, and a dispatch model) to develop emission factors both statewide and by major LSE. One central assumption made in the LBNL report was that plants located in a given service territory in California serve the load of that service territory. While this may be true for the state as a whole,[5] this may not hold true at the LSE level where unspecified purchases can originate from within the LSE's service territory, elsewhere in California, or other states. One strength of the report is that it accounted for all out of state plants owned or partially owned by California utilities, irrigation districts, and state agencies. However, the emissions associated with other imported power were still estimated using Northwest and Southwest averages.

3.2 Supplier Specific Averages for Imports

Another method explored in an Energy Commission staff report used a supplier-based approach rather than regional averages to determine the resource mix of imports (Loyer, 1998). Loyer assembled plant data for the utilities and power agencies exporting power to California to create a resource profile by supplier. California imports were then matched to each supplier and the total resource mix was aggregated up from the supplier-specific information. This analysis was only performed for the years 1994 and 1995. This method yields a higher GHG emission total than the static fuel shares used in the GHG inventory for the period from 1990 to 2000 (Bemis, 2006).

3.3 Regional Marginal

A new methodology for determining the generation mix of imports was proposed by Energy Commission staff in 2006 (Alvarado, 2006) with an update in 2007 (Alvarado and Griffin, 2007). The proposed methodology would improve on existing practice by more accurately determining the out of state resources dispatched to serve California load. It begins by accounting for all imports from specified sources, which was not consistently done in prior estimates. For emissions from unspecified net imports, staff conducted a marginal dispatch analysis of the Northwest and Southwest regions. In other words, this analysis recognizes that California is not served equally by all resources from out of state suppliers. For example, dispatch model runs for power imported over the Southwest interties revealed that the generation increased to provide exports to California comes primarily from natural gas while baseload coal facilities mostly serve the native load of the states where they are located. Compared to the average approach used for the net system power reports, the marginal methodology in the staff report would reduce the amount of coal assigned to California load (from 20 percent to 14 percent in 2005) and increase the amount of natural gas (from 38 percent to 44 percent). (Alvarado and Griffin, 2007)

[5] Since California is a large net importer, it is generally assumed that electricity generated in California is consumed in California. Thus, the question of unspecified purchases at the state level is primarily a matter of imports.

3.4 Differences between State Total and Retail Provider Estimates

The treatment of unspecified in-state resources may cause statewide estimates of California's resource mix to differ from inventories that will be conducted at the retail provider level. For the state inventory, it is generally assumed that electricity generated in California is consumed in California, and the unspecified resources refer primarily to imports. At the retail provider level unspecified purchases may originate from both in-state and out of state plants. In other words, while most power generated by IPPs in the state is consumed in California, it is not necessarily straightforward to track that power to the retail provider where load is ultimately served.

4. Categories of Sources

For purposes of reporting GHG emissions, the sources of power used to meet retail load can be broken down into two types: power that can be unambiguously tracked back to a specific facility and power that can only be tracked back to a mix of power plants at one of various geographic levels. These two types of sources are referred to as specified and unspecified sources. Further subcategories of these two types are described below.

4.1 Specified Sources

Specified sources include the energy that can be traced from a retail load back to specific power plants. Clear links to specific facilities generally exist when a retail provider owns generation facilities, has an equity share in a facility, or when a retail provider has a PPA with a specific facility. In some cases, certain utilities also receive allocations of power from federally-managed dams. The energy received from these facilities, and the GHG emissions associated with producing that energy, can be attributed to the receiving retail provider with reasonable certainty. Purchases from substantially identical collocated plants with a single interconnection may be treated the same as specified purchases for the purpose of this protocol.

4.1.1 Retail Provider Owned and Partially-Owned Facilities

Many retail providers in California own generation facilities. Even though the state's investor-owned utilities were required to divest many of their facilities under the restructuring agreement in the 1990s, they were allowed to retain ownership in hydro facilities, nuclear plants, out of state plants, and a small number of in-state plants where generation capacity was critical to meeting certain local load pockets. Recently, the Public Utilities Commission has begun to allow IOUs to begin investing in new generation facilities under certain conditions (e.g., Southern California Edison's Mountainview plant).

In addition to the facilities that are wholly owned by California retail providers, there are numerous facilities located in the Southwest that are partially owned by California retail providers and California agencies. Most of these plants are coal-burning facilities that were built in order for California utilities to procure low-cost baseload power located near coal deposits. In addition to the coal plants, there are also a nuclear plant and a gas plant located out of state that are partially owned by California utilities.

4.1.2 Qualifying Facilities

Some cogeneration and small power producers are certified by the Federal Energy Regulatory Commission (FERC) as qualifying facilities (QFs). Since the utilities to which these facilities are connected are currently obligated to take their power, the output from these facilities is treated very similarly to owned generation assets. All power taken and the associated emissions are assigned to retail load. Future market roles may change, as there is a possibility of regulatory action that could shift some QFs into the market.

4.1.3 Cogeneration

ARB's source-based reporting protocol will establish the accounting conventions for allocating cogeneration emissions between the steam host and the electricity sold to the grid. Retail providers should only report the emissions from the generation sold to the grid.

4.1.4 Facility-Specific Contracts

In some cases, a retail provider may have a PPA with a specific facility for all or some share of its generation. In order for a retail provider to claim the electricity and associated emissions from a specific facility, certain conditions must be imposed on facility specific purchases to ensure that the power purchased is truly inducing generation from the specified plant. In the absence of any eligibility criteria, contract shuffling is a possible outcome.

One condition that may allow claims on a plant's generation and emissions is the existence of a long-standing contractual relationship between a retail provider and a specified plant. For example, although the Boardman plant in Oregon is not partially owned by any California retail providers, its operator, Portland General Electric, has had a long-term contract to provide 15 percent of the plant's net output to San Diego Gas & Electric. As long as these types of relationships continue to exist, and total claims on these stations' power do not exceed 100%, retail providers will claim the generation received from these plants and the associated emissions. Some POUs have this type of arrangement with federally managed hydro stations, such as allocations of electricity from Hoover Dam to several Southern California POUs.

Staff believes that new claims to existing low- or zero-GHG plants should be treated with some skepticism since there is little reason to believe that an agreement between a retail provider and an existing plant will induce generation that would not have occurred anyway. This issue is akin to the additionality condition that is applied to project-based offsets in the Clean Development Mechanism and similar programs. Staff proposes that claims on existing sources meet certain conditions in order to mitigate the potential for contract shuffling by California retail providers. In the absence of limiting conditions, the quantity of low-GHG generation in the WECC region would enable California retail providers to easily meet GHG reduction targets while having little impact on dispatch or short-term investment (Bushnell et al., 2007).

One way to limit the pool of available clean resources might be to allow claims to facilities within the State of California, provided that the generating facility agrees to these claims. Such claims will need to be supported by contractual terms between the retail provider and the

IPP that operates the facilities. The emission rate assigned to remaining sales of an IPP allowing claims to specific plants will be adjusted to remove claimed facilities from its resource mix. A similar process would need to be developed for handling claims to facilities located out of state.

Since a retail provider's financial backing could help to change the mix of plants that are constructed to meet future electricity needs, claims to generation from new facilities should be allowed, at least in some circumstances. Clearly, any new plants owned or partially owned by a retail provider could be claimed by that retail provider for its own load. Other circumstances might also permit claims to new specified sources. For example, claims to a specific new facility might be permitted if a long-term PPA is signed between a retail provider and a developer prior to a plant's construction. The imposition of a pre-construction condition is to demonstrate a causal link between the retail provider and the addition of specified new capacity. By agreeing to a PPA upfront, the retail provider offers a guaranteed source of revenue to the developer that helps the developer obtain financing, thus establishing a clear causal link between the retail provider and the new clean generation.

4.2 Unspecified Sources

All purchases that cannot be tracked to specific power plants are categorized as unspecified resources. Some wholesale sellers are asset owning entities that sell power primarily from their own facilities. These entities consist of some vertically-integrated utilities, federal power agencies, and some IPPs. Other companies market power from a mix of affiliated generating companies as well as other wholesale market participants while other non-asset owning companies only market or broker power from other entities. Some purchases may also involve anonymous day-ahead or real-time markets where the buyers have no knowledge about which counterparties are providing the power. These types of unspecified purchases are described in more detail below.

4.2.1 Asset Owning Entities

Some participants in the wholesale market are primarily generators of electricity. While they may purchase some electricity to meet loads or contract obligations, they are not actively involved in the purchase of electricity for resale on the wholesale market. Thus, purchases of electricity from these entities can be traced to their own fleets of generating units with some degree of certainty. This may argue for the use of an emission factor for purchases from these entities that is calculated from the emission characteristics of their fleets. While this does not allow a retail provider to ascertain the exact facilities that were used to provide their power, it does limit the subset of plants upon which an emission factor can be based.

Some contracts for purchasing power from others may not meet our definition of "specified sources" because we have adopted the definition of "powerplant" used in Public Utilities Commission D.07-01-039 (the emissions performance standard decision), which is a relatively narrow definition. However such contracts may specify a group of essentially identical resources at a single location as the source of power. In that situation it may be more appropriate to use the emissions profile of those specific sources rather than a fleet-wide average. Where a retail provider can establish that the power it is purchasing actually comes from such a group of collocated "power plants" it should use the emissions profile of the group.

4.2.2 Electricity Marketers and Brokers

Marketers of electricity purchase power from a variety of generators and then resell the power either directly to retail providers or indirectly via other markets or brokers. In some cases a marketer is a company that serves as the trading arm of an affiliated company that owns and operates generating facilities. While it may be that a large share of the power sold by these marketers is ultimately sourced from their affiliates, without information on the purchases and sales by marketers, the generation sources used to meet marketer obligations must be regarded as highly uncertain. Similarly, brokers may procure power from a wide variety of sources in order to put together bundles of power to sell on the wholesale market. Since brokers do not report any of their transactions to a state agency, there is currently no source of information available to enable tracking of broker transactions.

4.2.3 CAISO Markets

Currently CAISO runs a real-time balancing market for participating retail providers to adjust to short-term fluctuations in load. Current policy directs retail providers to procure enough power to meet their expected needs and rely on the real-time market for no more than 5% of their loads. Beginning in 2008, CAISO will launch the IFM that will allow retail providers to purchase larger shares of power through CAISO. Once operational, the IFM is expected to account for roughly 10% to 20% of the total IOU loads (Market Advisory Committee Draft report, June 1, 2007).

5. Options for Assigning Emissions to Unspecified Sources

This section reviews the options for assigning emissions to the various types of unspecified sources and makes recommendations. The issues were addressed in the April 12 and 13 workshops for this proceeding and will not be repeated here. Readers are referred to the website: http://www.cpuc.ca.gov/static/energy/electric/climate+change/070411_ccevents.htm to review the presentations and papers presented during those workshops.

5.1 When Emission Factors are Calculated

One option for tabulating the total emissions for which a retail provider is responsible is for the State to evaluate a retail provider's settlements and assign emissions after the fact. This method would allow the State to monitor market conditions on an on-going basis and adjust emission estimates based on factors such as hydro availability and weather. Data on generation and emissions for sources of unspecified power (e.g., power plants, suppliers, or regions) would be collected from data reported to the State and federal agencies and emissions would be apportioned to retail providers based on the sources of their purchased power.

Another option is for the State to calculate ex ante emission factors that could be fixed at the start of a reporting period. If set before the year, parties will know the assigned carbon factor of any transactions they make, providing greater certainty regarding the total costs of power purchased. However, the greater certainty afforded by an ex ante approach comes at the expense of some accuracy in the factor, which will be set based on older information. While ex post tabulations of emissions would be based on actual generation data, ex ante factors would not. These emission factors would need to be calculated from generation, fuel consumption, and emissions data from Year 1 to calculate an emission factor during Year 2 for use in Year 3. For a large geographic region, emission factors should be relatively stable from year to year, although system emission factors in Northern California and the Northwest depend significantly on fluctuations in hydro conditions.

5.2 Regions for Defining Emission Factors

The options presented in this proceeding for assigning emissions to unspecified sources ranged from using the WECC average as a whole, to supplier based options, to not allowing any regional default values to be used. Although a single Western average is an option in the existing Registry protocol, most parties agreed that more detailed reporting should be required.

5.2.1 Regional Power Pools

The Registry's Power/Utility Reporting Protocol allowed parties to use the U.S. Environmental Protection Agency's eGRID Year 2000 average power pool numbers as a default value for spot market purchases (California Climate Action Registry, 2005). These are averages of total generation in the area and do not subtract out generation dedicated to another state or to native load. These CO_2 output emission rates were:

WECC California	805
WECC Great Basin (includes Nevada and Utah)	852
WECC Pacific Northwest	671
WECC Southwest	1,494
WECC Total	1,014

More recent eGRID subregion average emission rates have been published in eGRID Version 2.1, April 2007, which are based on 2004 data.

WECC California	879
WECC Northwest	921
WECC Southwest	1,254
WECC as a whole	1,107

Parties favoring use of eGRID factors may argue that more complex reporting protocols will be too costly and create market uncertainty for buyers and sellers. eGRId has the advantage of being readily available, does not require additional administrative time to compute and hence would improve market certainty.

On the other hand, eGRID numbers do not subtract out resources claimed to serve native load and do not distinguish among regional sellers. The only way that a California retail provider could reduce its out-of-state carbon footprint would be to reduce purchases, especially from the Southwest. Staff proposes a tracking mechanism by which California buyers could select among out-of-state sellers or regions those which have a carbon footprint which meets the buyer's needs.

The Energy Commission has also made various estimates of the resources serving California load using regional power pools. Because California has two major transmission paths, regional factors have been calculated for the Northwest and the Southwest. The characterization which the Energy Commission has used over the past fifteen years for its Net System Power is:

Northwest: Washington, Oregon, Idaho, Montana and B.C. Hydro

Southwest : Arizona, Nevada, New Mexico, Utah, and Colorado

While most parties have accepted this definition over the years, those who use EIA regions have defined the Northwest to exclude British Columbia and to include Nevada, Utah, Wyoming and eastern Colorado. Staff believes it is more accurate to characterize the Northwest as the western portion of the Northwest Power Pool plus British Columbia. This may change if new bulk transmission lines are constructed from the Rockies towards the west and south.

The WECC Southwest would be Arizona, western New Mexico, Imperial Irrigation District and the western tip of Texas. Given transmission constraints and known specific sellers, Imperial Irrigation District is part of California and should not be counted in the Southwest. The western tip of Texas is not a significant source of power for California and should also be excluded from the Southwest region for purposes of California reporting.

WECC-regional aggregations are attractive because data is available on that basis, and the analyst does not have to introduce estimation into assigning detailed profiles to specific sellers. Gross regional averages are unattractive to the extent that part of the regional resource is used to serve native load and hence is not available for export. Large regions may also include states with generators that do not sell into the California market either due to transmission constraints or because there are other, more attractive options elsewhere. (See Section 5.3.2 for adjusting regional averages to account for claimed power plants.)

Some parties are concerned that there could be cross-over between the Northwest and Southwest; i.e. sellers might resell power from one region in such a way that the seller claims it comes from one region but actually dispatches from the other. This did occur during the 2000-2001 energy crisis, and parties may be concerned that sufficiently different regional profiles could induce such contract shuffling and misrepresentation. The problems of contract shuffling and leakage are broader than just the cross-over issue, and they are addressed separately in Section 9.

In addition to providing factors for the imports from out of state sources, a default emission factor is also needed for unspecified purchases of power originating in California. This factor should not be based on eGRID values or other default factors because the Energy Commission possesses better data on generation that serves native load and other specified sources, such as those used for renewable portfolio standard (RPS) compliance. Much of this data is already provided to the Energy Commission for its Net System Power analysis. A default emission factor for unspecified sources in California would take into account the greater certainty of claimed resources in the state.

5.2.2 Control Area (Balancing Authority)

This option would require purchasers to track generation to its host control area. There are 35 control areas in the WECC, with five located in California (CAISO, Los Angeles Department of Water and Power, Sacramento Municipal Utility District, Imperial Irrigation District and Turlock Irrigation District). This option is attractive if the different control areas within the regional power pools are sufficiently different from each other and if the asset-owning seller is located in a single control area. It might be feasible for those direct purchases in which the seller can document the transaction with a NERC E-Tag (NERC, 2002). To date, facts have not been presented in this proceeding which would illuminate whether there is such intra-regional diversity or whether retail providers buy predominately from control areas whose carbon profile is substantially different from that of the surrounding region.

Parties have presented information on both the potential benefits and shortcomings of using an expanded NERC E-Tag or an equivalent process to track supplies to the host balancing authority. It is clear that this could not be implemented for 2008 reporting, due to the need for greater development of a western tracking system and problems such as the practice of ‘parking’ generation at a regional ‘hub’ and then reselling the power from that hub into California. It provides a potential starting point for developing a larger system. Retail providers that already get unit-specific data might voluntarily use existing tags to document their claims for emission factors for portfolios of resources.

5.2.3 Supplier

Asset Owning Entities

Under this option, asset owning sellers would be required to either document their source(s) of power or accept a regional or other default rate. The seller could provide either a fleet average or state in the contract that the supply is from a subset of resources not claimed for any other purpose. Some analysis will be necessary to determine the extent to which various asset owning entities are involved in the resale of electricity. If supplier-specific emission factors are allowed, patterns of purchases and sales for these entities will need to be monitored in order to ensure the continuing credibility of any emission factor used to assign emissions to purchases from these entities based on their generation fleets. Supplier certification would have to be monitored to assure that other claimed resources are not included and that these claims are plausible.

Marketers and Brokers

Since the sources of marketers' and brokers' power are subject to change from one day to another, assigning an ex-ante emission factor to their sales based on anything other than a generalized emission factor may not be feasible.

CAISO Markets

Purchases from CAISO markets are also characterized by a very low degree of specificity. Since the companies whose bids are accepted can change from day to day, season to season, and year to year, creating a reliable ex ante emission factor based on specific plants or fleets of plants for purchases from these markets is not feasible.

5.2.4 Default Only

Some parties have suggested that all unspecified purchases be required to use a default rate that characterizes either the marginal range of the dispatch (i.e. the less efficient units) or the highest emitting unit in the region. Suggestions made at the workshops included 1,100 lbs per MWh (a moderately efficient natural gas unit and, coincidentally, the WECC total average emissions rate) or 1,950 – 2,100 lbs per MWh, the rate of an existing pulverized coal unit. The purpose of the latter approach is to motivate buyers to use only specified sources in their portfolios. No one asserted that this was the actual regional average.

Since one of our criteria was that the tracking process be accurate, staff recommends against this approach. It potentially discriminates against portfolio sellers and the majority of generation available from out-of-state. If policy-makers want to eliminate unspecified contracts from the market, the process would have to be implemented over several years so that contracts could be rewritten. The impact of the policy on out-of-state participation in the CAISO's IFM would need to be studied. Since there are also unspecified contracts within California, comparable policies would be needed for in-state markets.

5.3 Determining the Subset of Facilities from a Pooled Purchase that Serves California Load

5.3.1 Average System Emission Factors

This approach assumes that the seller is providing power from its bundled system and has acquired resources with the intent of both selling to native load and to the market. This might be reasonable if there is a long-term contract, if the seller built generation ahead of load growth and has excess generation to sell, or if there is no state program that allows certain types of generation to be claimed to serve native load.

5.3.2 Adjusted Average: Accounting for Claimed Generation

A growing number of state programs either allow or require retail providers to designate the generation that serves their native load. Washington and Oregon have a formal tracking system in place, and several states are adding RPSs, which mandate that renewable energy meet a designated portion of native load. In order to expand our reporting protocols to be consistent with other Western states, claimed resources should not be counted as also sold to California retail providers. Implementing this would require the assistance of other states to verify that double-counting has not occurred. Staff has already started working with Washington and Oregon on their tracking systems, so a project could be undertaken as a pilot for sellers located in those states.

5.3.3 Marginal Emission Factors for Residual Unspecified Power

Once specified and claimed resources are identified (both those claimed by California entities and those claimed by entities in other states), the marginal method would assign a regional average based on the historic and future probable dispatch of the region. It is based on an analysis of past sales, system modeling, and attempts to verify expected sales patterns with other states. The method is documented in "Revised Methodology to Estimate the Generation Resource Mix of California's Electricity Imports", and was presented in the April workshops. This paper describes a method that allocates the unspecified resources based on a marginal generation analysis for the Southwest and on a hybrid method of marginal analysis and sales assessments for the Northwest. It reflects the increasing role of natural gas as the marginal resource throughout the West, while retaining the role of Northwest hydro power as a key swing resource for Northwest sales.

Because the CO_2 emissions factor of coal is roughly twice that of natural gas, estimates of Southwest imports are sensitive to the coal/natural gas split. Southwest coal is a baseload resource which runs at a steady capacity factor of 77%, with small variations from month to month except in March and April when units are typically shut down for maintenance. As a less expensive resource, it is always used by someone, and coal was largely built to serve native load. California utilities which wanted access to coal built or bought shares of units such as Mohave, Four Corners and Intermountain Power. In contrast to the even generation pattern typical of coal plants, records of transmission line loadings from the Southwest show that California imports power on peak but not off peak. Modeling runs of the Southwest power pool show that if California demand is decreased, coal continues to run but natural gas is shut down. Since 2000, the Southwest built a number of new gas combined cycles in excess of its own needs. For all these reasons, staff determined that the primary marginal generation from the Southwest is natural gas.

The modeling runs showed that 96% of the imports were natural gas and 4% coal. Workshop parties were supportive of the principal finding, that natural gas is the Southwest marginal resource. However, some parties asked staff to look again to determine if this might understate the role of coal. Staff looked at the possibility of additional coal contained in direct access contracts, the impact of dry hydro years, and the natural gas/coal price differential. Of these, staff believes that direct access contracts may have the largest impact on the changing the coal share. It is possible that ESPs could have some coal in their contracts because their customers are often large industrial and commercial facilities with high capacity factors that would use baseload power. For example, Arizona Public Service might serve its direct access customers with an integrated portion of its dispatch rather than as a separate resource mix. ESPs serve about 10% of California's load. Staff does not have evidence of how much of their load is served by coal, but to adjust for this uncertainty staff suggests a small adjustment to the model output.

For the 29% of Southwest contracts which are unspecified, the characterization would be 90% natural gas and 10% coal. Using reported fuel use and energy produced, staff estimated actual Southwest natural gas in 2005 to have an emissions factor of 951 lbs/MWh. Coal had a factor of 2,146 lbs/kWh. This yields a weighted average emissions factor of 1,075 lbs/MWh.

For the 88% of Northwest imports which are unspecified, the characterization would be 66% hydro, 9% coal, 2% nuclear, 22% natural gas, and 1% renewables. This produces a Northwest default emissions factor of 419 lbs CO_2/kWh. This factor is based on a coal emission rate of 2,146 lbs CO_2/MWh and a natural gas rate of 914 lbs CO_2/MWh. These rates were computed using actual fuel use and energy produced from Northwest units.

Using the 2005 data presented in the April workshops, staff has calculated the total emissions resulting from this method. Emissions from specified out-of-state resources total 32.63 $MMTCO_2e$, almost all from coal units owned by California utilities. Emissions from unspecified marginal resources are 8.82 $MMTCO_2e$ from the Southwest and 3.40 $MMTCO_2e$ from the Northwest.

In Section 2.3, this paper proposed that options be judged by the criteria of accuracy, simplicity, transparency, minimization of unintended consequences, and compatibility with reporting systems of other western states so that it can be expandable. (Consistency will be required of all options.)

Accuracy – At the April 12 workshop, parties generally agreed that the concept of this methodology was more accurate. The draft results presented there could be improved by better data that retail providers may be able to supply.

Simplicity – All regional average methods seem to have the same reporting burden issues, in that a state agency must certify the averages, and there is a trade-off between greater accuracy, such as accounting for claimed resources, and amount of information to be processed.

Transparency – Although marginal analysis does require some modeling of dispatch and transmission in the WECC region, the assumptions and methodology used by the Energy Commission are shared publicly and vetted by public comment.

Minimize unintended consequences – Since staff believes that it is the most accurate method for calculating regional emission factors, it is hoped this would reduce market distortions. While the Northwest's marginal emission rate is low, due to the dominance of hydropower in what is sold to California, purchases of lower emission power should not be penalized. Monitoring will be needed to verify whether contract shuffling is occurring at the Northwest hubs.

Expandability – The proposed method has been distributed to the other states in the western 5-state MOU. Washington and Oregon are willing to work with California to sort out claims and to separate out California sales from the sales to the rest of the Northwest. To date, Arizona and New Mexico have not identified a problem.

5.3.4 Unspecified Purchases within California

At the workshop, parties discussed the need to account for purchases from the CAISO real-time market, the forthcoming CAISO IFM, and other unspecified sources such as some DWR contracts and purchases from marketers and brokers. No proposals were made on what default factor might be used.

Since the real-time market is a balancing market where power is sold in five minute increments, it can be assumed that it comes from hydropower and natural gas units which can be ramped quickly. In the absence of data on the fuel shares, a split of 90% gas (1000 lbs CO_2/MWh) and 10% hydro (0 lbs CO_2/MWh) is proposed for further discussion. This results in a default factor of 900 lbs CO_2/MWh for the real-time market.

For the IFM, staff proposes starting with a default factor, in the hopes that after a year of operation, the CAISO can provide information to the State that will enable the calculation of a more accurate factor. Staff has discussed this possibility with the CAISO, and while they do not currently have this data readily available for the real-time market, it appears that it would be possible to establish an information sharing procedure between the CAISO and state agencies.

The IFM is likely to receive bids from all fuel sources, both out-of-state as well as in-state. For this market, and for unspecified bilateral deals within the state, staff considered the following options:

- use the average California emissions factor from eGRID (879 lbs CO_2/MWh)

- use the 2005 average emissions factor for all California, Northwest and Southwest natural gas (1,000 lbs CO_2/MWh)

- use an average California 2005 emissions factor for all fuels except nuclear and renewables, which are not assumed to be part of the day-ahead market. (790 lbs CO_2/MWh)

Staff recommends that the natural gas average emissions factor of 1,000 MWh be used. It is based on measured emissions of the principal marginal resource in the WECC region.

5.4 Differentiation by Time of Use

5.4.1 Reporting Options to Capture Seasonal or Time of Day Differences in Emission Rates

Some parties have suggested that their purchases are materially different than either the system average (if one is using the system average as a base) or the aggregate purchase patterns of other retail providers (if one is using a marginal residual emission factor). For example, little off-peak power is purchased, so a regional emission factor that includes baseload generation would overstate the role of baseload power in the purchases. Another example is that purchases from the Northwest are higher during the spring run-off season and dip in the winter.

The marginal emission rate approach takes this into account for California as a whole by incorporating these time-of-use patterns in imports. For example, it is common for some California retail providers to purchase power from the Northwest during spring run-off and to sell gas-fired generation to the Northwest in the winter. If a party could document that its time-of-day or seasonal purchases were significantly different than the general purchasing pattern, then they could make a demonstration to the State. Should this happen, the residual default rate would need to be recalculated so that the claimed resources no longer appear in the overall factor.

5.5 Accounting for Variation in Hydro Availability, Weather, and Business Cycles

While reporting requirements per se are not affected by hydro availability or weather, the accuracy of ex ante emission factors could be. These ex ante emission factors may underestimate or overestimate emissions in a given year if hydro conditions vary significantly from long-term averages. However, over the course of several years, inaccuracies that arise from the use of ex ante factors should tend to negate each other, as overestimates in one year compensate for underestimates in another.

Other aspects of this proceeding will also indirectly address this issue, such as having multi-year compliance periods and banking of allowances for use in dry or hot years. In recent years, the industry has developed a much better understanding of the impact of weather on loads. Those lessons should be applied in setting the compliance rules.

5.6 Evaluation of Data Sources

There are basically three kinds of data that pertain to the connection between retail providers and the power they procure to serve their customers: contracts, transmission data, and financial settlements. While some contracts may contain information on specific sources of power, many do not. Moreover, what is actually dispatched will frequently differ from contracts made years, months or days beforehand. The balancing authorities must manage the grid to maintain reliability, which may involve incrementing or decrementing units. Sellers may also find a cheaper resource or a cheaper transmission path and substitute it for their planned generation.

Transmission data on line loadings would not provide much useful information on the sources or sinks of power, but NERC E-Tags provide information about the transmission path that power will use to enter or exit a control area as well as the amount of power to be delivered, timing, chain of sellers, and source control area of the generation. Some parties have seen promise in E-Tags providing control area specific or even plant specific information for every purchase. In addition to the presentations provided at the April workshops by the Registry and the CAISO, staff has consulted with other utilities and with the E-Tag software vendor to better understand the feasibility of using E-Tags.

These parties have identified a few deficiencies in this approach for reporting purposes, including the fact that E-Tags do not often indicate the specific plant generating the power and that the tag can be broken in two ways. First, power can be sold to one entity at a certain point of delivery outside California. That entity can then resell power and a new E-Tag can be generated showing the original point of delivery as the new point of receipt. This frequently occurs when power is bought from multiple sources and then "parked" at a regional rub such as Palo Verde or California-Oregon Border. When sold into California, it may bear a tag from the hub instead of the original source control area. Similarly, a quantity of power may be bought by an entity and then broken down into smaller units before being resold. In these cases, the transactions may not carry the original source information with it. Additionally, E-Tags are not required for purchases within a control area, such as transactions within the CAISO territory.

Staff has not explored the regulatory feasibility of using E-Tags, which are managed by NERC rules and hence may be considered a FERC-jurisdictional system. Staff also has not explored the feasibility of getting access to the E-Tags and modifying them to meet the GHG tracking requirements.

While staff does not recommend using E-Tags at this time, we were heartened to learn of the availability of tracking software which might be modified to meet tracking needs. Along with the Western Renewable Energy Generation Information System (WREGIS), this demonstrates that it is technically feasible to move towards a mandatory tracking system for the West. The experiences of the NEPOOL and PJM regions also illustrate that a several year, multi-state process would be needed to get such a system operational.

The most accurate information of purchases is the financial settlements data, which is resolved approximately ninety days after the close of the month. These data reveal all of the purchases and sales made by a retail provider, with the quantities of electricity bought and sold by each counterparty. For purchases from asset owning entities primarily engaged in selling their own generation, these records provide a good indication of the sources of power consumed. However, these data do not illuminate the sources of power purchased from CAISO markets or through bilateral purchases from marketers and brokers.

Staff believes it would be too burdensome to attempt to scrutinize settlement data to measure actual generation which served load in every moment of the day. A combination of settlement data and contract terms regarding substitution should be sufficient to meet tracking needs. Monitoring could be used to determine whether substitution is a problem and whether the rule should be revisited before the implementation of the 2012 emission requirements.

5.7 Recommendation on Unspecified Sources

These recommendations are summarized in Table 1.

Assigning Emission Factors Before or After the Fact – Staff recommends ex ante assigning of emission factors to unspecified purchases. While staff is proposing that an ex ante approach be used in order to provide market certainty, we see merit in the greater accuracy of ex post reporting. Recommendations on other ways to balance this trade-off may present a better solution.

Regional Definition – Staff recommends using California's existing definitions of the Northwest and Southwest, with the option of allowing out-of-state suppliers to have the State certify their own power system emission factors. When the source region cannot be determined, the Southwest emission factor should be applied as the most conservative assumption.

Adjusting Regional Factors to Account for Claimed Generation – Staff proposes that the principle be adopted that tracking systems should exclude generation which is otherwise claimed to serve native load. The State should work with Washington and Oregon to establish a pilot project.

Marginal Emission Factors – Staff recommends that once specified purchases, claimed generation and ownership shares are subtracted from overall regional purchases, the remainder of the purchases should be counted as being served by the region's marginal resource mix, adjusted for reporting gaps.

Time of Day and Seasonal Adjustments – This option is probably not needed if a marginal emission factor and gross imports/exports are used. Staff recommends that retail providers have the option of documenting prior to a reporting period that their purchases are significantly different from the regional averages.

Table 1. Summary of Recommended Emission Factors

TYPE OF PURCHASE	RESOURCE TYPE	CO_2 EMISSION FACTOR (LBS/MWH)
In-state specified source	All fuels	Use emission factor source has provided to ARB for certification
Out-of-State specified source, includes ownership shares and contracts	Mostly coal, some renewables, gas, and nuclear	Calculate emission factor based on ARB methods. Coal factor range is 2,017 – 2,263
CAISO real time energy pool	Balancing energy *Mostly gas and hydro*	Use default factor of 900
CAISO Integrated Forward Market (pool)	All fuels, both in and out of state	Use default factor of 1,000
Other in-state unspecified sources	Unknown	Use default factor of 1,000
Out-of-state specified sellers (system purchase from asset-owning entity	Depends on seller	Request seller to obtain system average certification from ARB, net of resources claimed to serve native load
Northwest unspecified marginal generation	69% carbon-free, mostly hydro	Use default rate of 419
Southwest unspecified marginal generation	90% gas, 10% coal	Use default rate of 1,075

For comparison purposes the emission factors published for various regions and technologies are listed below:

A. Latest eGRID factors:

WECC California	879*
WECC Northwest	921
WECC Southwest (AZ/NM/southern NV,IID)	1,254
WECC as a whole	1,107

* This factor is higher than the factor which results from the state's Inventory. We have not been able to trace the difference. It includes northern Baja and excludes IID.

B. Technologies (regular annual factors, not start-up periods, not adjusted for losses))

New combined cycle	800 - 990
New combined cycle with duct-firing	810 - 1,020

Gas turbine – large frame	1,200 - 1300
Existing steam boilers	1,080 - 1640
Existing coal	1,950 – 2,560
Integrated Coal Gas	1,770

C. Regional fuel type averages (2005, EIA 906 form, + 7 ½% for transmission losses)

Natural gas	CA: 1,014	NW 982	SW 1,022
Coal		NW 2,307	SW 2,355

6. Treatment of Wholesale Sales by Retail Providers

Once the total pool of emissions for which a retail provider is responsible has been calculated from owned generation assets and purchases, adjustments must be made to account for wholesale sales. Since emission responsibility is assigned to retail load, retail providers are not responsible for emissions associated with power that is resold. However, the adjustments to emissions from wholesale sales may be performed in several ways that have significant implications for the emissions estimates. Methods differ according to which sources of electricity are assumed to produce the power sold on the wholesale market.

6.1 Three Methods for Assigning Emissions to Wholesale Sales

6.1.1 Pass-Through Method

There are basically three ways to assign emissions to wholesale sales. The first method, the “pass through” method, nets wholesale transactions so that sales are deducted from purchases and emissions are calculated for the difference (assuming that purchases are greater than sales). This method is generally used for statewide estimates of emissions or resource type used to meet California load (Marnay et al., 2002; Bemis, 2006; Alvarado and Griffin, 2007). The Power/Utility Protocol used by the Registry also relies on the pass-through approach. At the statewide level, this may not be a bad approximation since imports far outweigh exports and emissions associated with unspecified resources are generally based on large regionally aggregated power pools.

In essence, the pass through method assumes that all wholesale sales are analogous to wheeling arrangements in which the source of power sold is purchased power, not power from the retail provider’s own assets. When a retail provider buys and sells wholesale power at the same time, the pass-through method accurately conveys what is happening with the power at the wholesale level. However, this may not hold true in other circumstances.

6.1.2 Own-Generation Method

In contrast to the pass-through method, the own-generation method assumes that wholesale sales of electricity originate from a retail provider's own assets. The result is that the retail provider is responsible for all of the emissions associated with purchased power since none of the purchased power is assumed to pass-through the retail provider's system.

6.1.3 All-in Method: Average Mix of All Generation and Purchases

The all-in method begins with the sum of emissions from all owned generation and purchases. Wholesale sales are then assigned the emission rate of the average across this entire pool of emissions. In other words, the emissions associated with all owned generation and purchases are mixed into a homogenous product from which wholesale sales are drawn. The all-in method can also be adjusted so that generation and associated emissions from certain facilities are assumed to serve a retail provider's own load. Under this adjustment, only a subset of a retail provider's own facilities is averaged in with the purchased electricity to determine the emission characteristics of the wholesale sales.

6.2 Evaluation of the Three Methods

As discussed in a recent CDM technical paper the extent to which the method of treating wholesale sales for a net purchaser matters is a function of three factors (Murtishaw, 2007). First, gross purchases must make up a significant share of total load. If total purchases are trivial, the total emissions associated with purchases will have little effect on the total estimates. Second, there must be a significant difference between gross and net purchases. In other words, if the retail provider conducts very few wholesale sales, there will only be a small adjustment to the total pool of emissions from generation and purchases. Third, the average emission rate of the purchased power must differ appreciably from that of the owned generation assets.

Supposing that all of the above conditions are true, what are the implications of using one method compared to the other? This depends primarily on the relative emission rates of the owned assets compared to purchased electricity. The examples in Table 2 below illustrate how choice of method can affect a retail provider's total emission burden over the course of a reporting period. Table 2 shows two retail providers that each generate 100 MWh from their own assets, purchase 30 MWh with an average emission rate of 0.600 $MTCO_2$/MWh, and sell 20 MWh. Retail Provider 1 differs from Retail Provider 2 in that Retail Provider 1's own assets have an emission rate much lower than the emission rate of the purchased electricity while the contrary is true for Retail Provider 2. The sources of the emission factors assigned to wholesale sales are highlighted for each method.

The fundamental difference among the three methods lies in the calculation of the emission rate associated with resold electricity. In the pass-through method the average emission rate of the purchased electricity is used, in the own-generation method the average rate of the retail provider's own assets is used, and in the all-in method, the average emission rate of all generation and purchases is used. The pass-through method prevents the emissions associated with purchases that have been netted out from appearing in the retail provider's inventory. If the purchases have a higher emission rate than the owned generation, the retail provider benefits by having a lower total emission burden assigned to it. As Table 2 demonstrates, Retail Provider 1, whose own generation is relatively clean compared to purchases, benefits from the pass-through method.

Table 2. Sample Calculations of Total CO_2 Emissions Using Pass-Through, Own Generation, and All-In Methods

		Pass-Through		Own-Gen		All-In	
		RP 1	RP 2	RP 1	RP 2	RP 1	RP 2
Calculation of Emissions from Generation and Purchases	Generation from Own Assets, MWh	100	100	100	100	100	100
	Emission Rate, $MTCO_2$/MWh	0.400	0.800	0.400	0.800	0.400	0.800
	Emissions from Own Assets, $MTCO_2$	40	80	40	80	40	80
	Purchases, MWh	30	30	30	30	30	30
	Emission Rate, $MTCO_2$/MWh	0.600	0.600	0.600	0.600	0.600	0.600
	Emissions from Purchases	18	18	18	18	18	18
	Sub-total of Emissions, $MTCO_2$	58	98	58	98	58	98
	Sub-total of Gen & Purchases, MWh	130	130	130	130	130	130
	Avg Emission Rate, $MTCO_2$/MWh	0.446	0.754	0.446	0.754	0.446	0.754
Adjustment to Emissions from Sales	Load, MWh	110	110	110	110	110	110
	Wholesale Sales, MWh	20	20	20	20	20	20
	Emission Rate of Sales, $MTCO_2$/MWh	0.600	0.600	0.400	0.800	0.446	0.754
	Emissions Associated w/ Sales, $MTCO_2$	12	12	8	16	9	15
	Total Emissions, $MTCO_2$	46	86	50	82	49	83
	Final Em Rate (Total Emissions/Load)	0.418	0.782	0.455	0.745	0.446	0.754
	Pct Diff btwn Own Asset Em Rate & Final	4.5%	-2.3%	13.6%	-6.8%	11.5%	-5.8%

The proper choice of method depends on which one best reflects the circumstances of a retail provider's operations. If a retail provider is chronically unable to meet its load through its own assets, it may reasonably be assumed that its own assets are generally used to meet its own load. In this case, the retail provider likely engages in sales when it has over-procured power for its own needs either due to deviation between forecasts and actual load or because the combination of owned assets and must-take power exceeds the retail provider's needs.

Note that Table 2 shows two utilities that are net purchasers. The situation may be different for a retail provider that is a net seller, particularly if its own assets are generally sufficient to meet or exceed its load. A retail provider that is generally long may purchase power only during peak hours in periods of high seasonal demand or buy power to cover a maintenance outage at a large plant. In this case, sales originate primarily from the retail provider's own assets.

Patterns in purchases and sales may also differ by season and/or time of day. In this case, longer reporting periods may mask these seasonal differences. For example, it is possible that a retail provider may be self-sufficient during periods of intermediate demand, purchase power during the high-demand season, and sell power during the low-demand season. In this case, it sells from its own assets in the low season and purchases generation in the high season. In this example, the own-generation method is likely to most accurately represent the real nature of the transactions over a year.

The all-in method can be adjusted so that not all retail-provider owned assets are treated equally. For example, certain types of assets, like nuclear power plants, are used to produce baseload power that would rarely provide surplus power for sale. Generation from these facilities can reasonably be assumed to serve native load. Such treatment of baseload assets would be consistent with the proposed methodology to calculate emission rates for power purchased from regional power pools or specific sellers. Similarly, retail providers can assert that they conduct specified sales, reflecting the provisions for specified purchases. However, claims of specified sales should be subject to conditions that mirror those of specified sales.

6.3 Recommendation on Adjustment for Wholesale Sales

Staff recommends that an adjusted all-in method be used to calculate the total emissions assigned to each retail provider. For example, resources that are needed meet RPS obligations and certain deep baseload power plants (e.g., nuclear) would be assigned to cover native load. The same criteria that are applied to exclude certain resources from the mix of purchases from entities outside the state would be applied to wholesale transactions by covered entities in California. For retail providers that are consistently short, this method may be tantamount to the pass-through method if all owned resources are deemed to meet native load.

Since annual reporting may mask time of day or seasonal differences in patterns of purchases and sales, retail providers that contend the recommended method does not accurately reflect the nature of their wholesale transactions may petition the State to consider more disaggregated data. However, any exceptions to the adjusted all-in method must overcome a strong presumption that the recommended method is sufficiently accurate.

7. Recommendation for Electricity Sector Reporting Protocol

7.1 Covered Entities

All retail providers of electricity should be required to report under this protocol. This encompasses all IOUs, ESPs, CCAs, POUs, and WAPA. The State of California will also seek to cooperate with entities not required to report under this protocol such as CAISO, marketers, brokers, and WECC in order to obtain additional information on wholesale transactions in California and throughout the WECC region.

7.2 Determining Approved Emission Factors

7.2.1 State Calculated Ex Ante Annual Regional Default Factors

Staff recommends that the State of California calculate default emission factors for three subsections of WECC to be used for annual reporting: California, Pacific Northwest, and Southwest. Our recommendations for how to calculate these factors are listed in Section 5.7 above. These factors will be used to calculate emissions for all unspecified purchases that cannot be tracked back to more specific asset owning entities for which emission factors have been approved. The factors will be updated periodically, possibly every three years. The first set of factors to be used for 2008 reporting will be proposed in early 2008. Staff proposes that factors for subsequent periods be released by September 30 of the preceding year.

7.2.2 State Approved Supplier-Based Emission Factors

Staff recommends that the State approve supplier-based emission factors on a provisional basis to monitor the accuracy and reliability of this approach. The State of California (ARB with possible assistance from the Energy Commission) will certify supplier-based emission factors for in-state and out of state asset owning entities that agree to submit data on their wholesale transactions, generation from owned power plants, and the associated CO_2 emissions. The State will require attestation to the accuracy of the data before the certification can be approved. The approval process will be finalized by January 1, 2009 to be available for 2008 reporting.

7.3 What Data are Reported

7.3.1 Net Generation and Emission from Each Owned Facility

For each wholly owned facility, each reporting entity should provide the emissions for all GHGs and the generation data transmitted to ARB under the source-based reporting system, summed across the reporting period. For each partially owned facility, provide the same ARB approved source based data on generation and emissions as well as the quantity of net generation taken (electricity received at the point of delivery and associated transmission losses). Emissions should be allocated on the basis of the electricity taken. The reporting entity should provide an explanation whenever the share of net generation taken deviates from the ownership share in a partially owned plant.

7.3.2 Generation and Associated Emissions from Specified Purchases

For specified purchases from power plants that report to ARB, the retail provider should list the quantity of electricity purchased, including associated transmission losses. ARB would assign reported emissions from these plants based on the retail provider's share of net generation taken. For specified purchases from plants not reporting under ARB's source-based reporting (e.g. out of state plants) the retail provider should show the facility's net generation, fuel consumption data for each fuel from EPA Part 75, the heat content factor for each fuel, the emission factors in kg/MMBtu for each fuel, the oxidation factors for each fuel, and the total metric tons of CO_2, CH_4, and N_2O emitted. Then, the retail provider should adjust total emissions for share of net generation purchased.

7.3.3 Unspecified Purchases by Counterparty and Region

Each retail provider should list all wholesale purchases of power, including transmission losses, by counterparty. For each counterparty list the quantity of electricity purchased disaggregated by the three power pools defined in this protocol (Northwest, Southwest, and California). If there are any electricity purchases for which the region of origin cannot be determined, list these quantities as "unknown region."

7.3.4 Calculation of Emissions for Unspecified Purchases Using Approved Emission Factors

For counterparties for which the State of California has certified emission factors, the retail provider should multiply the purchases from each supplier by the certified emission factor. For remaining purchases, sum the purchases by region and multiply these purchases by the State provided emission factor. In order to avoid double-counting, retail providers should not calculate emissions for purchases from a given supplier using both supplier-specific data and regional factors.

7.3.5 Total CO_2e Emissions from Owned Facilities and Purchases

Reporting parties should sum the total CO_2, N_20, and CH_4 emissions from owned generation assets, specified purchases, and unspecified purchases as calculated in the above sections.

7.3.6 Wholesale Sales by Counterparty

Retail providers should show all wholesale sales by counterparty and region. The quantities of electricity listed should reflect the quantities as they departed the retail provider's system. In other words, these values should not include any transmission losses that occur between the point of receipt and purchaser's point of delivery.

7.3.7 Adjustments to Total Emissions from Wholesale Sales

The reporting entity should first calculate an adjustment emission factor for wholesale sales. This is done using the adjusted all-in method described in Section 6. The procedure starts with the total GHG emissions associated with owned generation and purchases in the numerator and total amount of electricity generated and purchased in the denominator. Adjustments are then made to both the total electricity and emissions to account for any claimed resources or specified sales approved by the State. Deduct the electricity received (or sold) from these sources, as measured at the point of delivery (or point of receipt for specified sales), and the associated emissions from the totals so that the adjusted numerator and denominator represent only unclaimed sources. The adjustment emission factor is the ratio of the unclaimed emissions to the unclaimed wholesale quantity of electricity received. An example of this calculation is shown below in Section 7.4.

To adjust the total GHG emissions for wholesale sales, multiply the quantity of wholesale electricity sold, as measured at the retail provider's point of receipt, times the adjustment emission factor. Deduct this quantity from the total of CO_2e emissions as calculated in Section 7.3.5. The adjusted quantity of emissions from owned generation and purchases is the quantity for which the retail provider is deemed responsible over the reporting period.

7.4 Sample Reporting Form [6]

Columns	1	2	3	4	5	6	7	8	9	10
Data Rows	**Section 1**	**Retail Load and Losses**								
1	Total Retail Load									
2	Total Load-Related Losses									
	Section 2	Owned Facilities								
	Plant Name	Net Gen	CO_2 Emissions Reported to ARB	N_2O Emissions Reported to ARB	CH_4 Emissions Reported to ARB		Total CO_2e	Adjustment for Receipts from Co-Owned	Adjusted CO_2e	Used Exclusively for Own Load?
3										
4										
	Section 3	**Specified Purchases**								
	Plant Name	Net Gen	CO_2 Emissions Reported to ARB	N_2O Emissions Reported to ARB	CH_4 Emissions Reported to ARB		Total CO_2e	Adjustment for Receipts from Co-Owned	Adjusted CO_2e	Used Exclusively for Own Load?
5										
6										
	Section 4	**Unspecified Purchases**	**Supplier Factor**							
	Supplier Name	Total Purchases at POR	Trans Losses	POR Purchases from NW	POR Purchases from SW	Purchases from CA	Purchases from Undetermined Region	Supplier Em Factor	Total CO_2e (EF x POR Purchases)	

[6] Note that this sample form is for illustrative purposes only. It does not reflect all of the steps that may be necessary for reporting under this protocol.

7										
	Section 5	**Unspecified Purchases**	**No Supplier Factor**							
	Supplier Name	Total Purchases at POR	Trans Losses	POR Purchases from NW	POR Purchases from SW	Purchases from CA	Purchases from Undetermined Region	CO_2e by Each Region using State Default EFs	Total CO_2e	
8										
	Section 6	**Sum of All Received Generation and Assoc'd Emissions**								
	CO_2e, MT, sum Column 9	MWh, at POR, sum Column 3								
10										
	Section 7	**Claimed Resources and Wholesale Adj Factor**								
	Sum CO_2e, for plants marked "Y" in C10	Sum Gen, Adjusted Gen, or POR for plants marked "Y" in C10								
11										
	Unclaimed CO_2e (R10C2- R11C2)	Unclaimed Electricity (R10C3- R11C3)	Adjustment EF (Divide R12C2 by R12C3)							

12										
	Section 8	**Adjustment for Wholesale Sales**								
	Purchaser	Sales at POR	Associated CO_2e (Sales times R12C3)							
13										
14										
15		Total Adjustment								
	Section 9	Total CO_2 Associated with Retail Load								
16	R10C1-R15C3									

8. Submission Process

8.1 State Agency Responsibilities for Receiving and Maintaining Data

ARB is the lead agency for tracking and monitoring all emissions data relevant to implementation of AB 32, so they will be the primary recipient of reports. The joint agencies will simultaneously receive copies of submissions and will support ARB, as necessary, in verifying the data.

8.2 Frequency

Our current understanding of ARB's plan is that they will require annual reports from sources, and that allowances will be issued on an annual basis. On the surface, therefore, it makes most sense to require annual reports from retail providers, because they must use the source data reported to ARB in order to compute their total emissions. If settlement data is available ninety days after the close of the month, staff proposes that load-based reports be due to ARB on May 15 for the previous year.

In-state generation data is already reported by sources to the Energy Commission on a quarterly basis and to the federal government monthly and annually. Loads also report to the Energy Commission on a quarterly basis. Therefore, the question arises whether there would be value in combining these reports and providing quarterly information on the load-based emissions. Some parties believe quarterly reports would increase transparency and give a running indication of how emissions allowances are being used throughout the year. Information was not presented in the workshops to demonstrate whether such quarterly reporting could be complete or meaningful, so staff has chosen not to recommend it during the first reporting periods. Once the systems are operational, they can be fine-tuned.

8.3 Verification

Parties agree that verification is vital to making our tracking system credible. ARB is developing a training and certification program for third party auditors and has proposed using third-party certification. ARB indicates that this training and certification would also apply to the load-based reporting.

9. Techniques for Addressing the Potential for Contract Shuffling and Leakage

Contract shuffling is the practice of claiming that one resource is sent to California, while leaving the high carbon intensive power to be sold in states which do not have a tracking system or a cap that requires allowances. Contract shuffling reduces the environmental integrity of AB 32 implementation, because no actual changes in total generation occur. The Market Advisory Committee has pointed out that there are sufficient low-carbon sources in the West to meet California's reduction goals, if all that power is labeled as being sold to California.

The main remedy for this is to develop a multi-state generation information system which would allow regulators to identify power which has been sold for another purpose. All MWh could be claimed only once. For such a system to help prevent leakage or contract shuffling, other states in the WECC region must adopt RPS requirements, binding GHG caps, or other systems that lead to sufficient scarcity for relatively clean sources of generation so that claims to low-carbon energy cannot be merely skimmed from the pool of WECC resources. With adequate demand for low-carbon resources and WECC-wide participation in a generation information system, a program of tradable emission attributes, as described at the April 13 workshop, could be established that would permit trading in unbundled emissions, much the same way as RECs are used for RPS compliance in Texas and other states.

There are two different ways that contract shuffling can occur. One form is facility-swapping, in which a California retail provider claims to receive power from a specific facility, when its purchases actually induce generation from another facility or mix of facilities. It is not necessary that California retail providers be aware of the facility swapping – it may happen without their knowledge or consent.

Figure 1. Illustration of Contract Shuffling

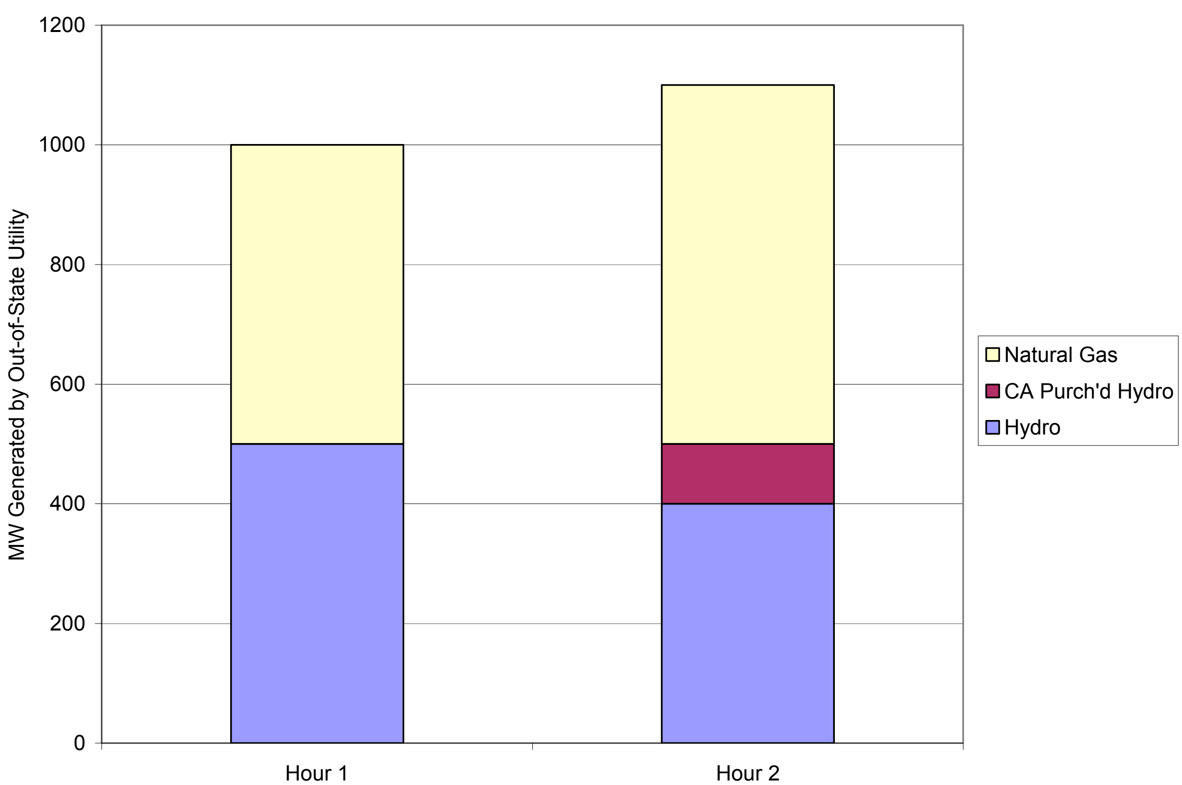

Figure 1 depicts an example of how this could occur. In Hour 1, an out-of-state utility is generating 1,000 MW to serve its own load. In Hour 2, a California retail provider has contracted to buy 100 MW of hydro power from this utility. The out-of-state utility must now generate 1,100 MW to serve its own load and meet its contractual obligation. The hydro resource is running at its maximum capacity of 500 MW, so the utility generates an additional

100 MW from natural gas plats and sells 100 MW of "hydro" to the California utility. The California utility believes it is purchasing hydro power, but its purchase is actually inducing natural gas generation. The proposed protocol attempts to deal with this possibility by imposing conditions on new claims to the generation of existing facilities.

A variation on contract shuffling and leakage is the practice of masking the carbon emissions factor of a source by claiming that it comes from a regional pool with a lower carbon factor. For example, a high-emitting unit could sell its power to the California-Oregon Border hub, and then claim that its power should be given the lower Northwest regional default value.

Staff believes that this latter practice will not occur on a widespread basis, due the daily and seasonal patterns of imports. California imports little off-peak unspecified power, and hence is much more likely importing natural gas from the Southwest as the marginal resource because coal plants are rarely ramped up to provide load-following power. Since most coal plants are cheaper to operate, their power is sold to native load whenever possible. Staff recognizes that the California system might incent individual sellers or buyers to attempt to evade the rule by engaging in "laundering" their high-emitting sources with a lower regional pool factor. If allowance prices are high, then the practice would be more rewarding.

In order to mitigate this possibility, the State will monitor purchasing patterns to check for changes in the daily pattern of imports. If a retail provider begins to import a significant amount of off-peak unspecified power, the marginal emission factors may be reevaluated. As a possible solution, differentiated baseload and load-following factors could be calculated and matched to disaggregated time of use reporting for purchases (Murtishaw, 2007).

During the learning period of the first few years of tracking, staff suggests the following actions to minimize and expose facility-swapping and power laundering:

- state in the rule that this is not an acceptable practice and that retail providers will be held accountable

- monitor use of regional default values and if it increases significantly, initiate an investigation to determine whether contract shuffling is happening.

- work with stakeholders to inculcate the understanding that contract shuffling will lessen the credibility of allowances, hence lessen their value in the market.

- act quickly if cases of contract shuffling are identified

- monitor changes in daily and seasonal patterns reflecting greater use of out-of-state baseload resources or increased use of aggregated contracts sold from regional hubs

- work with other states to quickly identify which resources are claimed for service to native load

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(End of Attachment A)